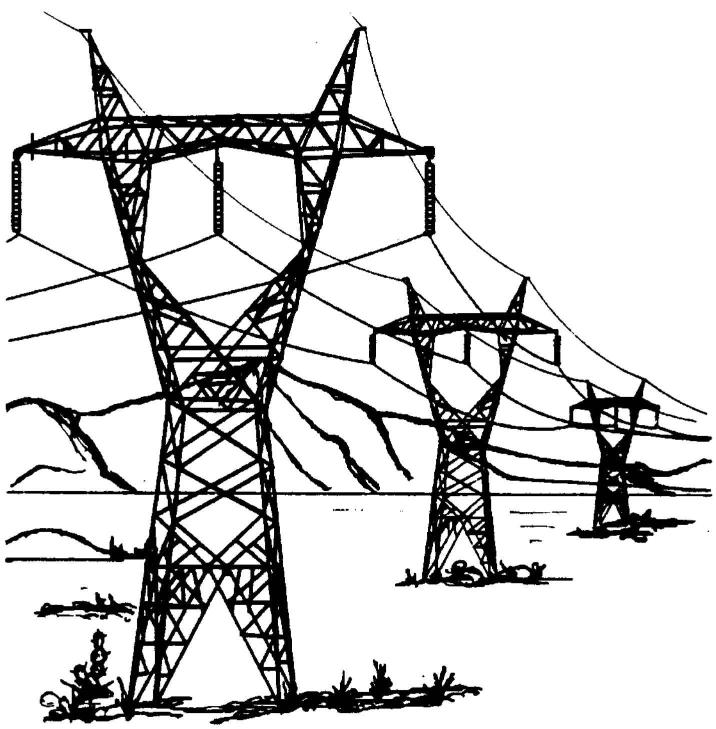
WESTERN AREA POWER ADMINISTRATION

CENTRAL ARIZONA PROJECT

115-KV AND 230-KV TRANSMISSION LINES



TRANSMISSION SERVICE RATE ADJUSTMENT BROCHURE
RATESETTING FISCAL YEAR 2006
RATE YEARS 2006 - 2010

WAPA-CAP-124

DESERT SOUTHWEST CUSTOMER SERVICE REGION

PROPOSED 115/230-kV TRANSMISSION SERVICE RATES

CENTRAL ARIZONA PROJECT

UNITED STATES DEPARTMENT OF ENERGY

WESTERN AREA POWER ADMINISTRATION

PHOENIX, ARIZONA

JULY 2005

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The Western Area Power Administration (Western) is proposing revised rates for the Central Arizona Project (CAP) firm point-to-point transmission service, nonfirm point-to-point transmission service, and Network Integration Transmission Service (NITS) on the CAP 115 kilovolt (kV) and 230-kV transmission lines. Current rates, under Rate Schedules CAP-FT1, CAP-NFT1 and CAP-NITS1, extend through December 31, 2005. Proposed rates will provide sufficient revenue to pay all annual costs, including interest expense, and repay required investment within the allowable period. Western will prepare a brochure that provides detailed information on the rates to all interested parties. Proposed rates, under Rate Schedules CAP-FT2, CAP-NFT2 and CAP-NITS2, are scheduled to go into effect on January 1, 2006, and will remain in effect through December 31, 2010.

The Deputy Secretary of Energy approved Rate Schedules CAP-FT1, CAP-NFT1, and CAP-NITS1 for transmission service effective January 1, 2001 (Rate Order No. WAPA-88, 65 FR 77368, December 11, 2000), and the Federal Energy Regulatory Commission (Commission) confirmed and approved the rate schedules on July 31, 2001, under FERC Docket No. EF01-5111-000 (96 FERC 62,094). Approval for Rate Schedules CAP-FT1, CAP-NFT1, and CAP-NITS1 covered 5 years beginning on January 1, 2001, ending on December 31, 2005.

II. RATE PROCESS

A. Public Process

Procedures adopted by DOE give interested parties an opportunity to participate in the development of power rates. The published procedures (10 CFR 903) for rate adjustments, as amended, are available upon request from Western's Desert Southwest Regional Office Power Marketing staff.

A Federal Register Notice (FRN) announcing the proposed rates and the consultation and comment period has been published and is included in Appendix A. This brochure, and its appendices, are being distributed to provide additional information.

The formal public consultation and comment period began with the publication of the FRN on July 1, 2005, and will end not less than 90 days after the publication date. During this time, interested parties may consult with and obtain information from Western representatives about the rate proposal. Interested parties also may examine data in the Power Repayment Studies (PRS). Copies of the PRS data and other supporting materials are available for public review at:

Western Area Power Administration
Desert Southwest Region
615 South 43rd Avenue
Phoenix, AZ 85009

B. Public Information and Public Comment Forums

A Public Information Forum will be held:

July 22, 2005 at 10:00 A.M.	Western Area Power Administration Desert Southwest Regional Office 615 South 43rd Avenue Phoenix, AZ 85009

During the Public Information Forum, representatives from Western and the Bureau of Reclamation, will explain the need for the proposed rate process and answer questions. Questions not answered at the Public Information Forum will be answered in writing before the end of the consultation and comment period. The public information forum will be recorded and transcribed. Copies of the transcript will be available for purchase from the firm providing the transcription service. (See Appendix G.)

A Public Comment Forum will be held:

August 22, 2005 at 1:00 p.m.	Western Area Power Administration Desert Southwest Regional Office 615 South 43rd Avenue Phoenix, AZ 85009

Interested persons may submit written or oral comments at the Public Comment Form. As with the Public Information Forum, the Public Comment Forum will be recorded and transcribed. Copies of the transcript will be available for purchase from the transcription service firm. (See Appendix G.)

C. Written Comments

All interested parties may submit written comments to Western any time during the consultation and comment period. All comments must be received by Western by the end of the comment period. Written comments should be sent to Mr. J. Tyler Carlson, Regional Manager, Desert Southwest Customer Service Region, Western Area Power Administration, P.O. Box 6457, Phoenix, AZ 85005-6457. A copy of the written comments should also be sent to Mr. Jack Murray, Rates Team Lead, Desert Southwest Customer Service Region, Western Area Power Administration, P.O. Box 6457, Phoenix, AZ 85005-6457.

D. Revision of Proposed Rates

During and after the consultation and comment period and the review of oral and written comments, Western may revise the proposed rates. If Western decides that further public comment on the revised proposed rate should be invited, an extension of the consultation and comment period may be initiated and one or more additional public meetings may be convened.

E. Decision on Proposed or Revised Proposed Rates

Following the end of the consultation and comment period, Western will develop a proposed rate. The Deputy Secretary may confirm, approve, and place these rates into effect on an interim basis. The decision, and an explanation of the principal factors leading to this decision, will be announced in the Federal Register. Western proposes to place the rates into effect on January 1, 2006.

F. Final Decision on Proposed Rates

The Deputy Secretary will submit all information concerning the interim rates to the FERC and request approval of the rates for the period of January 1, 2006, through December 31, 2010. The FERC may then confirm and approve the rate on a final basis, remand it to Western, or disapprove the rates.

G. Rate Activity Schedule

The following table displays Western's current schedule for processing the proposed CAP 115/230-kV transmission service rates:

TABLE I
CENTRAL ARIZONA PROJECT
RATE ACTIVITY SCHEDULE

SCHEDULED ACTIVITIES	DATES
Publish Federal Register Notice	July 1, 2005
Informal Public Information Meeting	July 12, 2005, 1:00 P.M.
Public Information Forum	July 22, 2005, 10:00 AM
Public Comment Forum	August 22, 2005, 1:00 PM
Close of Comment Period	September 29, 2005
Rates Effective	January 1, 2006

III. HISTORY OF TRANSMISSION SERVICE RATES

Transmission service rates for the CAP 115/230-kV transmission lines are established pursuant to the Department of Energy Organization Act (42 U.S.C. 7101, et seq.); the Reclamation Act of 1902 (32 U.S.C. 388, et seq.), as amended and supplemented by subsequent enactments, particularly section 9(c) of the Reclamation Project Act of 1939 (43 U.S.C. 485h(c)), and section 8 of the Act of August 31, 1964 (16 U.S.C. 837g).

A. Firm Transmission

The Assistant Commissioner of Reclamation in connection with Contract No. 7-07-30-P0006, dated and effective May 1, 1977, with the Citizens Utility Company (CUC) approved a transmission service charge of $2.20/kW-yr.

Since that time the contractual arrangements beginning March 1, 2005, UNS (formerly Citizen's Utilities Company) modified contract 87-BCA-10140, dated February 28, 2005, in which the Contractor agreed to pay Western monthly for the amount of CAP Transmission System capacity, expressed in kilowatts, contracted for and reserved for the Contractor's use at CAP Firm Transmission System point(s) of delivery set forth in Exhibit A in accordance with rates, charges, and conditions set out in the CAP Firm Transmission Rate Schedule.

The Deputy Secretary of Energy approved Rate Schedules CAP-FT1, CAP-NFT1, and CAP-NITS1 for transmission service effective January 1, 2001 (Rate Order No. WAPA-88, 65 FR 77368, December 11, 2000), and the Federal Energy Regulatory Commission (Commission) confirmed and approved the rate schedules on July 31, 2001, under FERC Docket No. EF01-5111-000 (96 FERC 62,094). Approval for Rate Schedules CAP-FT1, CAP-NFT1, and CAP-NITS1 covered 5 years beginning on January 1, 2001, ending on December 31, 2005.

B. Nonfirm Transmission

The first CAP nonfirm transmission service rate was 1.87 mills/kWh and was initially implemented in January 1, 2001. The proposed nonfirm rate, 1.66 mills/kWh will become effective January 1, 2006, on an interim basis, until FERC approves the rates on a permanent basis.

IV. PROPOSED RATES FOR TRANSMISSION SERVICE

Proposed rates for point-to-point transmission service and NITS on the CAP 115-kV and 230-kV transmission lines are based on a revenue requirement that recovers the CAP 115-kV and 230-kV transmission lines costs for facilities associated with providing transmission service and the non-facilities costs allocated to transmission service. Proposed rates for point-to-point transmission service on the CAP 115-kV/230-kV transmission system are determined by combining the average annual amortization costs with the average annual operations and maintenance costs, and dividing them by the average annual contract rate of delivery for the cost evaluation period, fiscal years FY 2006 – FY 2010.

TABLE II
PROPOSED POINT-TO-POINT CAP 115/230-KV TRANSMISSION SERVICE RATES

Type of Service	Existing Rates 115/230-kV System	Proposed Rates 115/230-kV System 1/1/2006	Percent Change
Firm Transmission Service	$9.83/kW/Year	$ 8.74/Kw/year	(11.09%)
Nonfirm Transmission Service	1.87 mills/kWh	1.66 mills/kWh	(11.23%)

The proposed rates reflect a 11.09% decrease due to decreases in operation and maintenance, principal, and interest cost for the five year period ending 2010. In addition, also contributing to the decrease, over the past five year period contract rate of deliveries increased which contribute proportionately to the percentage rate decrease. Implementing the proposed rates results in a firm point-to-point CAP 115-kV and 230-kV transmission line rate of $8.74 per kilowatt-year and a nonfirm point-to-point CAP 115-kV and 230-kV transmission line rate of 1.66 mills/kWh.

NITS allows a transmission customer to integrate, plan, economically dispatch, and regulate its network resources to serve its native load in a way comparable to how a transmission provider uses its own transmission system to service its native load customers. The monthly charge methodology for NITS on the CAP 115-kV and 230-kV transmission lines is the product of the transmission customer's load-ratio share times one-twelfth of the annual transmission revenue requirement. The customer's load-ratio share is calculated on a rolling 12-month basis. The customer's load-ratio share is equal to that customer's hourly load coincident with the CAP 115-kV and 230-kV transmission lines monthly transmission system peak divided by the resultant value of the CAP 115-kV and 230-kV transmission lines monthly transmission system peak minus the CAP 115-kV and 230-kV transmission lines coincident peak for all firm point-to-point transmission service plus the CAP 115-kV and 230-kV transmission lines firm point-to-point transmission service reservations. The proposed rates include the costs for scheduling, system control, and dispatch service.

A copy of the CAP 115/230-kV rate calculation study for FY 2006 is shown in Appendix E of this brochure.

V. FACTORS AFFECTING THE TRANSMISSION RATES

Repayment criteria are based on law and upon policies established by DOE Order RA 6120.2 (RA 6120.2), a copy of which is included in Appendix I of this brochure. According to RA 6120.2, project revenues are required to repay investment costs, including interest.

Generically, the repayment criteria formula is: total annual revenues equal total annual expenses plus debt repayment. Annual revenues are first used to pay the annual operating expenses. These annual operating expenses include all costs for operation, maintenance and interest on investments. Secondly, all required payments due on capitalized investments are paid.

The PRS on which this brochure is based may be updated with certain technical adjustments prior to final submittal to DOE for approval.

Information source for the PRS are discussed below:

A. 115/230-kV System

1. Sales

Historical firm transmission service sales are based on actual sales as reported in the Yearly Report of Energy Deliveries and Income. Future firm transmission service sales are based on the anticipated contractual obligations with existing and future contractors. The 115/230-kV system 5-year average contractual commitments are 840 megawatts (MW). The total combined firm transmission sales beginning in FY 2006 is projected to be 840 MW.

2. Firm Transmission Service Revenue

Historically firm transmission service revenues are based on actual firm transmission service revenue reported on the Yearly Report of Energy Deliveries and Income report and financial statements. Projections for future firm transmission service revenues are based on the projected future firm contractual sales multiplied by the proposed firm transmission service rate.

3. Other Revenue

Other revenue includes receipts from sources not otherwise addressed. Historically, the sources included have been nonfirm transmission sales, fuel replacement and interchange sales and settlements, rental of electric property, facility charges, and miscellaneous operating income.

4. Annual Expenses

a. Operation and Maintenance (O&M)

The O&M costs are the costs for maintaining and operating substations, switchyards, transmission lines, and administrative and general expenses.

While historical O&M data has been obtained from Western's financial statements, the O&M projections for future years of the cost evaluation period (2006-2010) are taken from Western's current budget documents. O&M costs for the out years (2006-2050) of the rate calculation PRS are based on the last budget year (2005) costs, less any non-recurring costs. The total O&M expense over the repayment period (2006-2050) of the rate calculation PRS is equal to $ 67,716,660.00.

Appendix C provides a detail of O&M expenses applicable to the proposed rate adjustment. Table III, identifies the elements that make up total O&M expenses.

The following Table I displays the elements that make up operation and maintenance expense for the CAP 115/230-kV transmission system:

TABLE III
ELEMENTS OF OPERATION AND MAINTENANCE EXPENSE FOR THE CAP 115-KV AND 230-KV TRANSMISSION LINES

CENTRAL ARIZONA PROJECT
WESTERN OPERATION AND MAINTENANCE BUDGET PROJECTION

Budget Activity	Facility Expenses	Estimated Annual Expenses FY 2006 – 2010
N/FGCA GWAMM	General Western Allocations	$133,099
N/FGCA SUPTM	IS Support Costs	$35,370
N/FGCA COMMM	Communications & Control Equipment	$99,154
N/FGCA ENVTX	Environmental Compliance	$0
N/FGCA SAFEM	Safety Expense	$10,911
N/FGCA SUBSM	O&M for Substations	$150,861
N/FGCA SUBCM	Direct Hours Not Identified-Substations	$51,556
N/FGCA LINSM	O&M for Transmission Lines	$80,568
N/FGCA LINCM	Direct Hours Not Identified- TLs	$11,569
N/FGCA RENTM	Multiproject Costs	$292,771
N/FGCA SVCMM	Service Facility Distribution Costs	$39,249
	Total Facility Expenses	**$905,108**
	Systemwide Expenses	
N/FGCA STUDM	Transmission & Engineering Studies	$52,228
N/FGCA BILLM	Power Billing & Collecting	$0
N/FGCA MRKTM	Power Marketing & Resources Planning	$123,791
N/FGCA SOLDM	System Operation & Load Dispatching	$418,507

Total Systemwide Expenses	**$594,526**
Total Facility & Systemwide Expenses	**$1,499,634**
Reclamation Annual O&M Costs	$54,684
Civil Service Retirement Expense	$38,367
CME Interest Expense	$632
Warehouse Interest Expense	$729
Facility Charge @ McCullough	$265,316
Total CME & Warehouse Expenses	**$359,728**
Estimated Total Expenses	**$1,859,362**

5. **Interest**

Interest expense on the unpaid balance of the federal investments is calculated annually and incorporated into the rate calculation PRS. The CAP 115/230-kV system Supporting Schedule to the rate calculation shows a cumulative total interest expense of $128,538,982 over the repayment period (1993-2043).

6. **Investments**

a. **Project**

This is the original investment of the CAP 115/230-kV transmission system which is to be repaid at a 3.342 percent interest rate over a 50 year period. The project total cumulative federal investment is $128,051,985. The allowable unpaid federal investment balance is $0 and is scheduled to be repaid by FY 2042.

b. **Additions & Replacements**

No capital additions or replacements are projected for the cost evaluation period FY 2006 – FY2010.

B. **Other Deductions**

Other deductions in the rate calculation PRS consist of an allocation for projections for portions of the unfunded Civil Service Retirement System cost, Capitalized Moveable Equipment Depreciation Expense, and interest on stores inventory items.

C. Nonfirm Transmission Service

Historical nonfirm transmission sales are based upon actual sales and are included in the figures from the Yearly Report of Energy Deliveries and Income. Projections of future nonfirm transmission sales are not made.

VI. REGULATORY FLEXIBILITY ANALYSIS

The Regulatory Flexibility Act of 1980 (5 U.S.C. 601 et seq.) requires Federal agencies to perform a regulatory flexibility analysis if a final rule is likely to have a significant economic impact on a substantial number of small entities and there is a legal requirement to issue a general notice of proposed rulemaking. This action does not require a regulatory flexibility analysis since it is a rulemaking of particular applicability involving rates or services applicable to public property.

VII. ENVIRONMENTAL COMPLIANCE

In compliance with the National Environmental Policy Act of 1969 (NEPA), (42 U.S.C. 4321, et seq.); Council on Environmental Quality Regulations (40 CFR parts 1500-1508); and DOE NEPA regulations (10 CFR Part 1021), Western has determined that this action is categorically excluded from preparing an environmental assessment or an environmental impact statement.

VIII. DETERMINATION UNDER EXECUTIVE ORDER 12866

Western has an exemption from centralized regulatory review under Executive Order 12866; accordingly, no clearance of this notice by the Office of Management and Budget is required.

IX. SMALL BUSINESS REGULATORY ENFORCEMENT FAIRNESS ACT

Western has determined that this rule is exempt from congressional notification requirements under 5 U.S.C. 801 because the action is a rulemaking of particular applicablity relating to rates or services and involves matters of procedure.

APPENDIX A

FEDERAL REGISTER NOTICE

ENTITLED

Proposed Rates for Transmission Service on the Central Arizona Project 115-kV and 230-kV Transmission Lines

Central Arizona Project

number of the person protesting or intervening; and (4) otherwise comply with the requirements of 18 CFR 385.2001 through 385.2005. All comments or terms and conditions must set forth their evidentiary basis and otherwise comply with the requirements of 18 CFR 4.34(b). Agencies may obtain copies of the application directly from the applicant. A copy of any protest or motion to intervene must be served upon each representative of the applicant specified in the particular application. A copy of all other filings in reference to this application must be accompanied by proof of service on all persons listed in the service list prepared by the Commission in this proceeding, in accordance with 18 CFR 4.34(b) and 385.2010.

You may also register online at *http://www.ferc.gov/docs-filing/esubscription.asp* to be notified via e-mail of new filings and issuances related to this or other pending projects. For assistance, contact FERC Online Support.

Magalie R. Salas,
Secretary.
[FR Doc. E5–3453 Filed 6–30–05; 8:45 am]
BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Western Area Power Administration

Central Arizona Project-Rate Order No. WAPA–124

AGENCY: Western Area Power Administration, DOE.

ACTION: Notice of proposed transmission rates.

SUMMARY: The Western Area Power Administration (Western) is proposing revised rates for the Central Arizona Project (CAP) firm point-to-point transmission service, nonfirm point-to-point transmission service, and Network Integration Transmission Service (NITS) on the CAP 115 kilovolt (kV) and 230-kV transmission lines. Current rates, under Rate Schedules CAP–FT1, CAP–NFT1 and CAP–NITS1, extend through December 31, 2005. Proposed rates will provide sufficient revenue to pay all annual costs, including interest expense, and repay required investment within the allowable period. Western will prepare a brochure that provides detailed information on the rates to all interested parties. Proposed rates, under Rate Schedules CAP–FT2, CAP–NFT2, and CAP–NITS2, are scheduled to go into effect on January 1, 2006, and will remain in effect through December 31, 2010. Publication of this **Federal Register** notice begins the formal process for the proposed rates.

DATES: The consultation and comment period begins today and will end September 29, 2005. Western will present a detailed explanation of the proposed rates at a public information forum. The public information forum is: July 22, 2005, 10–12 p.m. MST, Phoenix, AZ.

Western will accept oral and written comments at a public comment forum. The public comment forum will be held on the following date: August 22, 2005, 1 p.m. MST, Phoenix, AZ.

ADDRESSES: Send written comments to Mr. J. Tyler Carlson, Regional Manager, Desert Southwest Customer Service Region, Western Area Power Administration, P.O. Box 6457, Phoenix, AZ 85005–6457, e-mail *carlson@wapa.gov.* Western will post official information about the rate process on its Web site at *http://www.wapa.gov/dsw/pwrmkt/CAPTRP/CAPTRP.htm.* Western will post official comments received via letter and e-mail to its Web site after the close of the comment period. Western must receive written comments by the end of the consultation and comment period to ensure they are considered in Western's decision process. The public information forum and public comment forum will be held at: Western's Desert Southwest Region (DSWR) office, 615 South 43rd Avenue, Phoenix, AZ.

FOR FURTHER INFORMATION CONTACT: Mr. Jack Murray, Rates Team Lead, Desert Southwest Customer Service Region, Western Area Power Administration, P.O. Box 6457, Phoenix, AZ 85005–6457, telephone (602) 605–2442, e-mail *jmurray@wapa.gov.*

SUPPLEMENTARY INFORMATION: Proposed rates for the CAP 115-kV and 230-kV transmission lines are designed to recover an annual revenue requirement that includes investment repayment, interest, operation and maintenance expense, and other expenses.

The Deputy Secretary of Energy approved Rate Schedules CAP–FT1, CAP–NFT1, and CAP–NITS1 for transmission service effective January 1, 2001 (Rate Order No. WAPA–88, 65 FR 77368, December 11, 2000), and the Federal Energy Regulatory Commission (Commission) confirmed and approved the rate schedules on July 31, 2001, under FERC Docket No. EF01–5111–000 (96 FERC 62,094). Approval for Rate Schedules CAP–FT1, CAP–NFT1, and CAP–NITS1 covered 5 years beginning on January 1, 2001, ending on December 31, 2005.

Proposed rates for point-to-point transmission service and NITS on the CAP 115BkV and 230-kV transmission lines are based on a revenue requirement that recovers the CAP 115BkV and 230-kV transmission lines costs for facilities associated with providing transmission service and the non-facilities costs allocated to transmission service. Proposed rates for point-to-point transmission service on the CAP 115-kV/230-kV transmission system are determined by combining the average annual amortization costs with the average annual operations and maintenance costs, and dividing them by the average annual contract rate of delivery for the cost evaluation period, fiscal years FY 2006–FY 2010.

PROPOSED POINT-TO-POINT CAP 115/230-KV TRANSMISSION SERVICE RATES

Type of service	Existing rates 115/230-kV system	Proposed rates 115/230-kV system 1/1/2006	Percent change
Firm Transmission Service	$9.83/kW/Year	$8.74/kW/year	(11.09)
Nonfirm Transmission Service	1.87 mills/kWh	1.66 mills/kWh	(11.23)

The proposed rates reflect a 11.09% decrease due to decreases in operation and maintenance, principal, and interest cost for the five year period ending 2010. Implementing the proposed rates results in a firm point-to-point CAP 115-kV and 230-kV transmission line rate of $8.74 per kilowattyear and a nonfirm point-to-point CAP 115-kV and 230-kV transmission line rate of 1.66 mills/kWh.

NITS allows a transmission customer to integrate, plan, economically dispatch, and regulate its network resources to serve its native load in a way comparable to how a transmission provider uses its own transmission system to service its native load customers. The monthly charge methodology for NITS on the CAP 115-kV and 230-kV transmission lines is the product of the transmission customer's load-ratio share times one-twelfth of the annual transmission revenue requirement. The customer's load-ratio share is calculated on a rolling 12-month basis. The customer's load-ratio share is equal to that customer's hourly load coincident with the CAP 115-kV and 230-kV transmission lines monthly transmission system peak divided by the resultant value of the CAP 115-kV and 230-kV transmission lines monthly transmission system peak minus the CAP 115-kV and 230-kV transmission lines coincident peak for all firm point-to-point transmission service plus the CAP 115-kV and 230-kV transmission lines firm point-to-point transmission service reservations.

The proposed rates include the costs for scheduling, system control, and dispatch service.

Legal Authority

Western is establishing rates for transmission service on the CAP 115-kV and 230-kV transmission lines under the Department of Energy Organization Act (42 U.S.C. 7101–7352); the Reclamation Act of 1902 (ch. 1093, 32 Stat. 388), as amended and supplemented by subsequent laws, particularly section 9(c) of the Reclamation Project Act of 1939 (43 U.S.C. 485h(c)); and other acts that specifically apply to the project involved.

By Delegation Order No. 00–037–00, effective December 6, 2001, the Secretary of Energy delegated: (1) The authority to develop power and transmission rates to Western's Administrator; (2) the authority to confirm, approve, and place such rates into effect on an interim basis to the Deputy Secretary of Energy; and (3) the authority to confirm, approve, and place into effect on a final basis, to remand, or to disapprove such rates to the Commission. Existing Department of Energy (DOE) procedures for public participation in power rate adjustments (10 CFR part 903) were published on September 18, 1985.

Availability of Information

All brochures, studies, comments, letters, memorandums, and other documents Western initiates or uses to develop the proposed rates are available for inspection and copying at the DSWR office, located at 615 South 43rd Avenue, Phoenix, Arizona. Many of these documents and supporting information are also available on its Web site at *http://www.wapa.gov/dsw/pwrmkt/CAPTRP/CAPTRP.htm*.

Regulatory Procedure Requirements

Regulatory Flexibility Analysis

The Regulatory Flexibility Act of 1980 (5 U.S.C. 601, *et seq.*) requires Federal agencies to perform a regulatory flexibility analysis if a final rule is likely to have a significant economic impact on a substantial number of small entities and there is a legal requirement to issue a general notice of proposed rulemaking. This action does not require a regulatory flexibility analysis since it is a rulemaking of particular applicability involving rates or services applicable to public property.

Environmental Compliance

In compliance with the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321, *et seq.*); Council on Environmental Quality Regulations (40 CFR parts 1500–1508); and DOE NEPA Regulations (10 CFR part 1021), Western has determined this action is categorically excluded from preparing an environmental assessment or an environmental impact statement.

Determination Under Executive Order 12866

Western has an exemption from centralized regulatory review under Executive Order 12866; accordingly, no clearance of this notice by the Office of Management and Budget is required.

Small Business Regulatory Enforcement Fairness Act

Western has determined that this rule is exempt from congressional notification requirements under 5 U.S.C. 801 because the action is a rulemaking of particular applicability relating to rates or services and involves matters of procedure.

Dated: June 17, 2005.

Michael S. Hacskaylo,

Administrator.

[FR Doc. 05–13010 Filed 6–30–05; 8:45 am]

BILLING CODE 6450–01–P

ENVIRONMENTAL PROTECTION AGENCY

[ER–FRL–6664–8]

Environmental Impacts Statements; Notice of Availability

Responsible Agency: Office of Federal Activities, General Information (202) 564–7167 or *http://www.epa.gov/compliance/nepa/*.

Weekly receipt of Environmental Impact Statements Filed 06/20/2005 Through 06/24/2005 Pursuant to 40 CFR 1506.9.

EIS No. 20050256, Draft EIS, AFS, MT, Beaverhear-Deerlodge National Forest Draft Revised Land and Resource Management Plan, Implementation, Beaverhead, Butte-Silver Bow, Deerlodge, Granite, Jefferson, Madison Counties, MT, Comment Period Ends: 08/15/2005, Contact: Marty Gardner 406–683–3860.

EIS No. 20050257, Final EIS, AFS, MT, Northeast Yaak Project, Proposed Harvest to Reduce Fuels in Old Growth, Implementation, Kootenai National Forest, Three Rivers Ranger District, Lincoln County, MT, Wait Period Ends: 08/01/2005, Contact: Kathy Mohar 406–295–4693.

EIS No. 20050258, Final EIS, AFS, OR, B&B Fire Recovery Project, Proposed Harvest of Fire-Killed Trees, Reduction of Fuels, Planting of Tree, Deschutes National Forest, Sisters Ranger District, Jefferson and Deschutes Counties, OR, Wait Period Ends: 08/01/2005, Contact: Brent Ralston 541–383–5784.

EIS No. 20050259, Draft EIS, FHW, NY, Southtowns Connector/Buffalo Outer Harbor Project, Improvements on the NYS Route 5 Corridor from Buffalo Skyway Bridge to NYS Route 179, in the City of Buffalo, City of Lackawanna and Town of Hamburg, Erie County, NY, Comment Period Ends: 08/15/2005, Contact: Amy Jackson-Grove 518–431–4131.

EIS No. 20050260, Draft EIS, AFS, AK, Scott Peak Project Area, Harvesting Timber and Development of Road Management, Tongrass National Forest, Petersburg Ranger District, Northeat of Kupreanof Island, AK , Comment Period Ends: 08/15/2005, Contact: Patty Grantham 907–772–3871.

EIS No. 20050261, Final EIS, IBR, CA, Cental Valley Project Long-Term Water Service Contract Renewals -American River Division, Proposes to Renew Long-Term Water Service Contracts, Sacramento, Placer and El Dorado Counties, CA, Wait Period Ends: , 08/01/2005Contact: David Robinson 916–989–7179.

EIS No. 20050262, Draft EIS, FHW, DC, Klingle Road Reconstruction Project, Reconstructing for Vehicular and Recreational Uses, Between Porter Street, NW and Cortland Place, NW, Funding, Washington, DC, Comment Period Ends: 08/15/2005, Contact: Michael Hicks 202–219–3513.

EIS No. 20050263, Final EIS, AFS, CA, Power Fire Restoration Project, To Reduce Long-Term Fuel Loading for the Purpose of Reducing Future

APPENDIX B

PROJECT NARRATIVE

APPENDIX B
PROJECT NARRATIVE
Central Arizona Project

The Central Arizona Project (CAP) was authorized by passage of the Colorado River Basin Project Act (Act of September 30, 1968, Public Law 90-537, 82 Stat. 885) for the purposes of furnishing irrigation water and municipal water supplies to the water-deficient areas of Arizona and western New Mexico through direct diversion or exchange of water, conservation and development of fish and wildlife resources, enhancement of recreation opportunities, and for other purposes.

The Secretary of Interior was directed to construct, operate and maintain the CAP, consisting of the following principal works: (1) a system of main conduits and canals, including a main canal and pumping plants for diverting and carrying water; (2) water storage facilities and power-pumping plants; (3) aqueducts and pumping plants; (4) related canals, regulating facilities, hydroelectric powerplants, and electrical transmission facilities required for the operation of said principal works; (5) related water distribution and drainage works; and (6) appurtenant works.

The Colorado River Basin Project Act also authorized Federal participation with non-Federal interests for construction, operation and maintenance of thermal generating powerplants (i.e., Navajo Generating Station) whereby the United States acquired the rights to plant capacity, including the delivery of power and energy over appurtenant transmission facilities (i.e., Navajo Southern and Western Transmission Systems) to mutually agreed upon delivery points, as the Secretary of Interior determines is required to provide pumping power for the CAP.

When not required for the CAP, the power and energy may be disposed of by the Secretary of Interior for other purposes at such prices the Secretary determines, including its marketing in conjunction with the sale of power and energy from Federal powerplants in the Colorado River system so as to produce the greatest practicable amount of power and energy that can be sold at firm power and energy rates.

On August 4, 1977, the Department of Energy Organization Act (Public Law 95-91, 91 Stat. 565; 42 U.S.C. Sections 7101 was signed into law, establishing the Department of Energy (DOE). Section 302(a)(3) of the Act created the Western Area Power Administration within DOE. Section 302(a)(1)(E) transferred the power marketing functions of the Bureau of Reclamation , including the construction, operation, and maintenance of transmission lines and attendant facilities to the DOE.

APPENDIX C
OPERATION AND MAINTENANCE

EXPENSES

CENTRAL ARIZONA PROJECT
WESTERN OPERATION AND MAINTENANCE BUDGET PROJECTION

Budget Activity	Facility Expenses	Estimated Annual Expenses FY 2006 – 2010
N/FGCA GWAMM	General Western Allocations	$133,099
N/FGCA SUPTM	IS Support Costs	$35,370
N/FGCA COMMM	Communications & Control Equipment	$99,154
N/FGCA ENVTX	Environmental Compliance	$0
N/FGCA SAFEM	Safety Expense	$10,911
N/FGCA SUBSM	O&M for Substations	$150,861
N/FGCA SUBCM	Direct Hours Not Identified-Substations	$51,556
N/FGCA LINSM	O&M for Transmission Lines	$80,568
N/FGCA LINCM	Direct Hours Not Identified- TLs	$11,569
N/FGCA RENTM	Multiproject Costs	$292,771
N/FGCA SVCMM	Service Facility Distribution Costs	$39,249
	Total Facility Expenses	**$905,108**
	Systemwide Expenses	
N/FGCA STUDM	Transmission & Engineering Studies	$52,228
N/FGCA BILLM	Power Billing & Collecting	$0
N/FGCA MRKTM	Power Marketing & Resources Planning	$123,791
N/FGCA SOLDM	System Operation & Load Dispatching	$418,507
	Total Systemwide Expenses	**$594,526**
	Total Facility & Systemwide Expenses	**$1,499,634**
	Reclamation Annual O&M Costs	$54,684
	Civil Service Retirement Expense	$38,367
	CME Interest Expense	$632
	Warehouse Interest Expense	$729
	Facility Charge @ McCullough	$265,316
	Total CME & Warehouse Expenses	**$359,728**
	Estimated Total Expenses	**$1,859,362**

APPENDIX D

RATE SCHEDULE

Rate Schedule CAP-FT2
Supersedes Rate Schedule CAP-FT1

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION

CENTRAL ARIZONA PROJECT

SCHEDULE OF RATE(S) FOR FIRM POINT-TO-POINT CAP 115-kV/230-kV TRANSMISSION SERVICE

Effective:

The first day of the first full billing period beginning on or after January 1, 2006, through December 31, 2010.

Available:

In the marketing area served by the Central Arizona Project (CAP) 115-kV/230-kV transmission system.

Applicable:

The transmission service customers shall compensate the CAP where firm capacity and energy are supplied to the CAP 115-kV/230-kV transmission system at points of interconnection with other systems and transmitted and delivered, less losses, to points of delivery on the CAP 115-kV/230-kV system specified in the service contract. The formula for the annual revenue requirement used to calculate the charges for this firm service under this schedule was promulgated and may be modified pursuant to applicable Federal laws, regulations, and policies.

The Desert Southwest Customer Service Region (DSW) may modify the charges for firm point-to-point transmission service upon written notice to the transmission customer. Any change to the charges to the transmission customer for firm point-to-point transmission, shall be as set forth in a revision to this rate schedule promulgated pursuant to applicable Federal laws, regulations, and policies and made part of the applicable service contract. DSW shall charge the transmission customer in accordance with the revenue requirements then in effect.

Character and Conditions of Service:

Alternating current at 60 Hertz, three-phase, delivered and metered at the voltages and points of delivery established by contract over the CAP 115-kV/230-kV transmission system.

Formula Rate For Firm Point-to-Point Transmission Service:

Annual Rate = Five Year Average Annual Revenue Requirement divided by the Five Year Average Contract Rate of Delivery, rounded to the penny.
Monthly Rate = Annual Rate divided by 12, rounded to the penny.

Calculated Rates

For FY 2006, the annual firm rate calculates to $8.74 per kW-year, and the monthly firm rate calculates to $0.73 per kW-month. Based on updated financial and load data, recalculated rates will go into effect on January 1 of each year during the effective rate schedule period.

Adjustments:

For Reactive Power:

There shall be no entitlement to transfer of reactive kilovoltamperes at delivery points, except when such transfers may be mutually agreed upon by contractor and contracting officer or their authorized representatives.

For Losses:

Capacity and energy losses incurred in connection with the transmission and delivery of capacity and energy under this rate schedule shall be supplied by the customer in accordance with the service contract.

Billing for Unauthorized Overruns:

For each billing period in which there is a contract violation involving an unauthorized overrun of the contractual firm transmission obligations, such overrun shall be billed at 10 times the above rates.

Rate Schedule CAP-NFT2
Supersede Rate Schedule CAP-NFT1

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION
CENTRAL ARIZONA PROJECT
SCHEDULE OF RATE(S) FOR NONFIRM POINT-TO-POINT CAP
115-kV/230-kV TRANSMISSION SERVICE

Effective:

The first day of the first full billing period beginning on or after January 1, 2006, through December 31, 2010.

Available:

In the marketing area served by the Central Arizona Project 115-kV/230-kV transmission system.

Applicable:

The transmission service customer shall compensate the Central Arizona Project (CAP) for nonfirm point-to-point transmission service where capacity and energy are supplied to the CAP 115-kV/230-kV transmission system at points of interconnection with other systems, transmitted subject to the availability of the transmission capacity, and delivered less losses, to points of delivery on the CAP 115-kV/230-kV system specified in the service contract.

Character and Conditions of Service:

Alternating current at 60 Hertz, three-phase, delivered and metered at the voltages and points of delivery established by contract over the CAP 115-kV/230-kV transmission system.

Formula Rate for Nonfirm Point-to-Point Transmission Service:

Nonfirm Point-To-Point Transmission Service Rate: Each Contractor shall be billed monthly a mills per kilowatthour rate of scheduled or delivered kilowatthours at point of delivery, established by contract, payable monthly. This rate is equal to the CAP 115-kV/230-kV Firm Transmission dollar per kilowatt-year rate then in effect divided by 8,760, multiplied by 1,000, rounded to two decimal places.

Calculated Rate:

For FY 2006, the nonfirm rate calculates to 1.66 mills/kWh. Based on updated financial and load data, a recalculated rate will go into effect on January 1 of each year during the effective rate schedule period.

Adjustments:

For Reactive Power:

There shall be no entitlement to transfer of reactive kilovoltamperes at delivery points, except when such transfers may be mutually agreed upon by contractor and contracting officer or their authorized representatives.

For Losses:

Capacity and energy losses incurred in connection with the transmission and delivery of capacity and energy under this rate schedule shall be supplied by the customer in accordance with the service contract.

UNITED STATES DEPARTMENT OF ENERGY
WESTERN AREA POWER ADMINISTRATION
DESERT SOUTHWEST CUSTOMER SERVICE REGION

CENTRAL ARIZONA PROJECT

SCHEDULE OF RATE(S) FOR NETWORK INTEGRATION TRANSMISSION SERVICE

Effective:

The first day of the first full billing period beginning on or after January 1, 2006, through December 31, 2010.

Applicable:

The transmission customer shall compensate the Central Arizona Project (CAP) each month for Network Integration Transmission Service (NITS) pursuant to the applicable Network Integration Transmission Service Agreement and annual revenue requirement referred to below. The formula for the annual revenue requirement used to calculate the charges for this service under this schedule was promulgated and may be modified pursuant to applicable Federal laws, regulations, and policies.

The Desert Southwest Customer Service Region (DSW) may modify the charges for NITS upon written notice to the transmission customer. Any change to the charges to the transmission customer for NITS shall be as set forth in a revision to this rate schedule promulgated pursuant to applicable Federal laws, regulations, and policies and made part of the applicable service agreement. DSW shall charge the transmission customer in accordance with the revenue requirement then in effect.

Formula Rate:

Monthly Charge = Transmission Customer's Load-Ratio Share x
(Revenue Requirement / 12)

Calculated Rate:

The projected annual revenue requirement for FY 2006 for the CAP 115-kV/230-kV transmission system is $6,935,468. Based on updated financial and load data, a recalculated revenue requirement will go into effect on January 1 of each year during the effective rate schedule period.

APPENDIX E

RATE METHODOLOGY STUDY

Central Arizona Project

Fiscal Year 2006 - 2010

Rate Setting FY 2006

WAPA-124

Effective January 1, 2006

CENTRAL ARIZONA PROJECT
ESTIMATED ANNUAL REVENUE REQUIREMENT
Fiscal Year 2005 Power Repayment Study
(ANNUAL REVIEW CEP FY 2006 - FY 2010)

O&M Expenses	1,499,634
Other Expenses	
Unfunded Civil Service Retirement Expense	38,367
CME Depreciation & Interest Expense	632
Warehouse Interest Expense	729
ESTIMATED RECLAMATION ANNUAL O&M COSTS	54,684
Facility Charge @ McCullough	265,316
Interest Expense	
Investment (Principal & Interest)	5,477,965
Principal Payment	
Estimated Total Annual Gross Expenses	7,337,326
Estimated Total Annual Other Revenue	
Estimated Annual Revenue Requirement	7,337,326

Current Rate determination/calculation for 115/230-KV system rate:

$8.74	**/KW-year**
$0.73	**/KW-month**
$0.17	**/KW-week**
$0.020	**/KW-day**
$0.00100	**/KWh**

Non-Firm Transmission Rate **1.66 mills/kWh**

CENTRAL ARIZONA PROJECT
115/230-KV Transmission System
RATE DESIGN

The formula rate design calculates the net average annual costs for the 5-year Cost Evaluation Period, and divides it by the sum of the contractors 5-year average contract rate of delivery (CROD), rounded to the penny.

Total Estimated Annual Costs		5-Year Average CROD			Rates	
$7,337,326.40	/	839,869	kW	=	$8.74	$/kW-Year [1/]
					$0.73	$/kW-Month [2/]
					$0.17	$/kW-Week [3/]
					$0.02	$/kW-Day [4/]
					1.00	mills/kWh [5/]
Non-Firm Transmission Rate					1.66	mills/kWh

[1/] $/kW-Yr = Total Estimated Annual Costs Divided By 5-Year Average CROD, rounded to the penny
[2/] $/kW-Month = $/kW-Year divided by 12 months, rounded to the penny
[3/] $/kW-Week = $/kW-Year divided by 52 weeks, rounded to the penny
[4/] $/kW-Day = $/KW-Year divided by 365 Days, rounded to the penny
[5/] mills/kWh = ($/kW-Year divided by 8,760 hours) multiplied by 1,000, rounded to 2 decimals

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CENTRAL ARIZONA PROJECT

WESTERN OPERATION AND MAINTENANCE BUDGET PROJECTIONS

Budget Activity	Facility Expenses	Estimated Average Annual Expenses FY 2006 - FY2010
N/FGCA GWAMM	General Western Allocation	$133,099
N/FGCA SUPTM	IS Support Costs	$35,370
N/FGCA COMMM	Communications & Control Equipment	$99,154
N/FGCA ENVTX	Environmental Compliance	$0
N/FGCA SAFEM	Safety Expense	$10,911
N/FGCA SUBSM	O&M for Substations	$150,861
N/FGCA SUBCM	Direct Hours Not Identified-Substations	$51,556
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N/FGCA RENTM	Multiproject Costs	$292,771
N/FGCA SVCMM	Service Facility Distribution Costs	$39,249
	Total Facility Expenses	**$905,108**
	Systemwide Expenses	
N/FGCA STUDM	Transmission & Engineering Studies	$52,228
N/FGCA BILLM	Power Billing & Collecting	$0
N/FGCA MRKTM	Power Marketing & Resources Planning	$123,791
N/FGCA SOLDM	System Operation & Load Dispatching	$418,507
	Total Systemwide Expenses	**$594,526**
	Total Facility & Systemwide Expenses	**$1,499,634**
	Estimated Reclamation Annual O&M Costs	$54,684
	Unfunded Civil Service Retirement Expense	$38,367
	CME Depreciation & Interest Expense	$632
	Warehouse Interest Expense	$729
	Facility Charge @ McCullough	$265,316
	Total CME & Warehouse Expenses	**$359,728**
	Estimated Total Expenses	**$1,859,362**

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CENTRAL ARIZONA PROJECT

ANNUAL AVERAGE ESTIMATED COSTS
FOR COST EVALUATION PERIOD FY 2006 TO FY 2010

AVERAGE ANNUAL AMORTIZATION COSTS

ANNUAL AMORTIZATION			
Principal	$9,475,846.90		
Interest	$17,913,975.88		
	$27,389,822.79		
AVERAGE ANNUAL AMORTIZATION COSTS		$5,477,964.56	
AVERAGE ANNUAL AMORTIZATION COSTS			$5,477,964.56

OPERATION & MAINTENANCE COSTS

ESTIMATED WESTERN ANNUAL O&M COSTS	$1,499,633.76	
ESTIMATED RECLAMATION ANNUAL O&M COSTS	$54,684.10	
ESTIMATED ADDITIONAL WESTERN EXPENSES		
Unfunded Civil Service Retirement Costs	$38,367.46	
Capitalized Movable Equipment	$631.67	
Warehouse Stores	$728.55	
Facility Charge @ McCullough	$265,316.31	
TOTAL ESTIMATED ANNUAL O&M EXPENSE		$1,859,361.84

SUBTOTAL ESTIMATED ANNUAL COSTS	$7,337,326.40
TOTAL NET ESTIMATED ANNUAL COSTS	$7,337,326.40

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CENTRAL ARIZONA PROJECT

TRANSMISSION CAPITAL INVESTMENT REPAYMENT

Fiscal Year	Investment Repaid with Interest: Principal	Investment Repaid with Interest: Interest	Total Yearly Principal and Interest Payments
1994	$1,280,519.85	$4,279,497.34	$5,560,017.20
1995	$1,280,519.85	$4,236,702.37	$5,517,222.22
1996	$1,280,519.85	$4,193,907.40	$5,474,427.25
1997	$1,280,519.85	$4,151,112.42	$5,431,632.28
1998	$1,280,519.85	$4,108,317.45	$5,388,837.30
1999	$1,280,519.85	$4,065,522.48	$5,346,042.33
2000	$1,280,519.85	$4,022,727.50	$5,303,247.36
2001	$1,664,675.81	$3,979,932.53	$5,644,608.34
2002	$1,664,675.81	$3,924,299.07	$5,588,974.87
2003	$1,664,675.81	$3,868,665.60	$5,533,341.41
2004	$1,664,675.81	$3,813,032.13	$5,477,707.94
2005	$1,664,675.81	$3,757,398.67	$5,422,074.48
2006	$1,664,675.81	$3,701,765.20	$5,366,441.01
2007	$1,664,675.81	$3,646,131.74	$5,310,807.55
2008	$2,048,831.76	$3,590,498.27	$5,639,330.04
2009	$2,048,831.76	$3,522,026.31	$5,570,858.08
2010	$2,048,831.76	$3,453,554.36	$5,502,386.12
2011	$2,048,831.76	$3,385,082.40	$5,433,914.16
2012	$2,048,831.76	$3,316,610.44	$5,365,442.21
2013	$2,048,831.76	$3,248,138.48	$5,296,970.25
2014	$2,048,831.76	$3,179,666.53	$5,228,498.29
2015	$2,561,039.70	$3,111,194.57	$5,672,234.27
2016	$2,561,039.70	$3,025,604.62	$5,586,644.33
2017	$2,561,039.70	$2,940,014.68	$5,501,054.38
2018	$2,561,039.70	$2,854,424.73	$5,415,464.43
2019	$2,561,039.70	$2,768,834.78	$5,329,874.49
2020	$2,561,039.70	$2,683,244.84	$5,244,284.54
2021	$2,561,039.70	$2,597,654.89	$5,158,694.59
2022	$3,329,351.61	$2,512,064.94	$5,841,416.56
2023	$3,329,351.61	$2,400,798.01	$5,730,149.63
2024	$3,329,351.61	$2,289,531.08	$5,618,882.69
2025	$3,329,351.61	$2,178,264.15	$5,507,615.76
2026	$3,329,351.61	$2,066,997.22	$5,396,348.83
2027	$3,329,351.61	$1,955,730.29	$5,285,081.90
2028	$3,329,351.61	$1,844,463.36	$5,173,814.97
2029	$3,457,403.60	$1,733,196.42	$5,190,600.02
2030	$3,457,403.60	$1,617,650.00	$5,075,053.60
2031	$3,457,403.60	$1,502,103.57	$4,959,507.17
2032	$3,457,403.60	$1,386,557.14	$4,843,960.74
2033	$3,457,403.60	$1,271,010.71	$4,728,414.31
2034	$3,457,403.60	$1,155,464.28	$4,612,867.88
2035	$3,457,403.60	$1,039,917.85	$4,497,321.45
2036	$3,457,403.60	$924,371.43	$4,381,775.03
2037	$3,457,403.60	$808,825.00	$4,266,228.60
2038	$3,457,403.60	$693,278.57	$4,150,682.17
2039	$3,457,403.60	$577,732.14	$4,035,135.74
2040	$3,457,403.60	$462,185.71	$3,919,589.31
2041	$3,457,403.60	$346,639.28	$3,804,042.88
2042	$3,457,403.60	$231,092.86	$3,688,496.46
2043	$3,457,403.60	$115,546.43	$3,572,950.03
TOTAL PAID AT END OF REPAYMENT	$128,051,985.18	$128,538,982.25	$256,590,967.43

Principal Repayment

Years 1-7	1% of Total Cap Expense
Years 8-14	1.3% of Total Cap Expense
Years 15-21	1.6% of Total Cap Expense
Years 22-28	2% of Total Cap Expense
Years 29-35	2.6% of Total Cap Expense
Years 36-50	2.7% of Total Cap Expense

Repayment Interest

3.342% Interest Rate
Simple Interest on Unpaid Principal

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CENTRAL ARIZONA PROJECT

Project
Grp 3 3.3420%

Supporting Schedule

(1)

Year	Interest Paid	Principal Payment	Unpaid Balance	Allowable Unpaid Balance	Cumulative Balance	Incremental Annual Investment
1993	0	0	128,051,985	128,051,985	128,051,985	128,051,985
1994	4,279,497	1,280,520	126,771,465	128,051,985	128,051,985	0
1995	4,236,702	1,280,520	125,490,945	128,051,985	128,051,985	0
1996	4,193,907	1,280,520	124,210,426	128,051,985	128,051,985	0
1997	4,151,112	1,280,520	122,929,906	128,051,985	128,051,985	0
1998	4,108,317	1,280,520	121,649,386	128,051,985	128,051,985	0
1999	4,065,522	1,280,520	120,368,866	128,051,985	128,051,985	0
2000	4,022,728	1,280,520	119,088,346	128,051,985	128,051,985	0
2001	3,979,933	1,664,676	117,423,670	128,051,985	128,051,985	0
2002	3,924,299	1,664,676	115,758,995	128,051,985	128,051,985	0
2003	3,868,666	1,664,676	114,094,319	128,051,985	128,051,985	0
2004	3,813,032	1,664,676	112,429,643	128,051,985	128,051,985	0
2005	3,757,399	1,664,676	110,764,967	128,051,985	128,051,985	0
2006	3,701,765	1,664,676	109,100,291	128,051,985	128,051,985	0
2007	3,646,132	1,664,676	107,435,616	128,051,985	128,051,985	0
2008	3,590,498	2,048,832	105,386,784	128,051,985	128,051,985	0
2009	3,522,026	2,048,832	103,337,952	128,051,985	128,051,985	0
2010	3,453,554	2,048,832	101,289,120	128,051,985	128,051,985	0
2011	3,385,082	2,048,832	99,240,289	128,051,985	128,051,985	0
2012	3,316,610	2,048,832	97,191,457	128,051,985	128,051,985	0
2013	3,248,138	2,048,832	95,142,625	128,051,985	128,051,985	0
2014	3,179,667	2,048,832	93,093,793	128,051,985	128,051,985	0
2015	3,111,195	2,561,040	90,532,754	128,051,985	128,051,985	0
2016	3,025,605	2,561,040	87,971,714	128,051,985	128,051,985	0
2017	2,940,015	2,561,040	85,410,674	128,051,985	128,051,985	0
2018	2,854,425	2,561,040	82,849,634	128,051,985	128,051,985	0
2019	2,768,835	2,561,040	80,288,595	128,051,985	128,051,985	0
2020	2,683,245	2,561,040	77,727,555	128,051,985	128,051,985	0
2021	2,597,655	2,561,040	75,166,515	128,051,985	128,051,985	0
2022	2,512,065	3,329,352	71,837,164	128,051,985	128,051,985	0
2023	2,400,798	3,329,352	68,507,812	128,051,985	128,051,985	0
2024	2,289,531	3,329,352	65,178,460	128,051,985	128,051,985	0
2025	2,178,264	3,329,352	61,849,109	128,051,985	128,051,985	0
2026	2,066,997	3,329,352	58,519,757	128,051,985	128,051,985	0
2027	1,955,730	3,329,352	55,190,406	128,051,985	128,051,985	0
2028	1,844,463	3,329,352	51,861,054	128,051,985	128,051,985	0
2029	1,733,196	3,457,404	48,403,650	128,051,985	128,051,985	0
2030	1,617,650	3,457,404	44,946,247	128,051,985	128,051,985	0
2031	1,502,104	3,457,404	41,488,843	128,051,985	128,051,985	0
2032	1,386,557	3,457,404	38,031,440	128,051,985	128,051,985	0
2033	1,271,011	3,457,404	34,574,036	128,051,985	128,051,985	0
2034	1,155,464	3,457,404	31,116,632	128,051,985	128,051,985	0
2035	1,039,918	3,457,404	27,659,229	128,051,985	128,051,985	0
2036	924,371	3,457,404	24,201,825	128,051,985	128,051,985	0
2037	808,825	3,457,404	20,744,422	128,051,985	128,051,985	0
2038	693,279	3,457,404	17,287,018	128,051,985	128,051,985	0
2039	577,732	3,457,404	13,829,614	128,051,985	128,051,985	0
2040	462,186	3,457,404	10,372,211	128,051,985	128,051,985	0
2041	346,639	3,457,404	6,914,807	128,051,985	128,051,985	0
2042	231,093	3,457,404	3,457,404	128,051,985	128,051,985	0
2043	115,546	3,457,404	0	0	128,051,985	0
HISTORICAL SUBTOTAL	128,538,982	128,051,985	0	0	128,051,985	128,051,985

CENTRAL ARIZONA PROJECT
CONSTRUCTION COSTS OF TRANSMISSION LINES, SUBSTATIONS, AND SWITCHYARDS
FROM INCEPTION THROUGH SEPTEMBER 30, 2004

COST AUTHORITY	DESCRIPTION	Prior to FY 74	1974	1975	1976	3 Month 1976	1977	1978	1979	1980	1981
1450	Davis-Parker No. 2 230-kV TL	331,073.10	52,926.30	644,009.69	4,421,314.28	1,612,028.94	1,782,140.35	(822.23)	6,756.09	6,337.77	11,599.48
1451	Parker-Havasu 230 kV TL							12,112.61	4,749.84	60,015.03	116,348.19
1452	New Waddell-Westwing 230 kV TL										
1455	Liberty-Parker 230-kV TL		104,157.37	7,708.52	56,637.03	90,206.17	831,390.84	1,432,990.51	10,131,473.37	357,520.82	116,657.51
1460	McCullough-Mead 230-kV TL				15,345.72			(15,345.72)			
1461	Mead-Davis 230 kV TL				87,204.99			33,053.49	218,786.11	232,502.23	154,748.00
1462	Harcuvar-Little Har Pmp Plnt 115 kV TL						19,989.14	21,725.00	13,632.34	76,502.92	66,476.72
1463	Harcuvar-Bouse Hills Pmp Plnt 115 kV TL						2,285.86	21,838.16	19,196.93	50,869.31	39,201.59
1464	Hassayampa- Pmp Plnt 230 kV							29,186.25	597.77	79,042.59	99,305.26
1465	Spook Hill-Salt Gila Pmp Plnt 69 kV TL									8,859.68	12,711.18
1466	ED-2-Saguaro 115-kV TL										
1467	Blk Mtn-Del Bac 115 kV TL										
1468	Rattlesnake Tap-Blk Mtn TL										
1650	Davis Switchyard 230-kV Additions	33,708.14	17,351.85	52,403.18	119,996.46	478,118.24	1,914,049.27	783,425.98	286,222.64	227,360.41	11,079.17
1655	Parker Switchyard 230-kV Additions	49,165.08	8,521.98	62,358.72	95,498.28	19,751.44	1,795,150.32	569,726.62	238,367.95	116,837.74	17,786.33
1660	Liberty Substation Additions			9,869.49	1,930.08	3,088.18	55,030.11	390,946.61	64,945.14	93,910.51	11,283.31
1662	McCullough Switching Station Additions				53,464.09				2,619.76	7,974.50	212,025.54
1663	Coolidge Substation Additions				21,788.95						634.45
1670	Harcuvar Substation						6,045.51	91,576.10	113,559.02	237,450.89	110,534.22
1671	Hassayampa Substation						3,901.80	28,512.32	14,516.47	52,616.66	30,642.78
1672	Spook Hill Substation									6,578.91	1,600.35
1673	New Waddell Westwing Substation										
1675	ED-2 Substation Additions										
1676	Saguaro Substation Additions										
1677	Rattlesnake Tap Substation										
1678	Del Bac Substation										
	Construction Costs	413,946.32	182,957.50	776,349.60	4,873,179.88	2,203,192.97	6,409,983.20	3,398,925.70	11,115,423.43	1,614,379.97	1,012,634.08
3.342%	Interest During Construction 1/	6,917.04	16,891.31	32,921.33		164,140.32	389,497.33	553,404.20	795,938.97	1,008,653.99	1,052,551.39
TOTAL INVESTMENT COST		**420,863.36**	**199,848.81**	**809,270.93**	**4,873,179.88**	**2,367,333.29**	**6,799,480.53**	**3,952,329.90**	**11,911,362.40**	**2,623,033.96**	**2,065,185.47**

1/ IDC = (1/2 Current Year Construction Cost MULTIPLIED BY Project Interest Rate) **PLUS** (Cumulative Prior Year Construction Costs MULTIPLIED BY Project Interest Rate)
Project Declared Substantially Complete in FY 1993. Repayment Started in FY 1994.

CENTRAL ARIZONA PROJECT
CONSTRUCTION COSTS OF TRANSMISSION LINES, SUBSTATIONS, AND SWITCHYARDS
FROM INCEPTION THROUGH SEPTEMBER 30, 2004

COST AUTHORITY	DESCRIPTION	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
1450	Davis-Parker No. 2 230-kV TL	16,010.70	14,427.49	987.36	49,016.00			602.43			
1451	Parker-Havasu 230 kV TL	118,004.88	1,245,130.81	73,141.39	541.81	170,989.95	1,802.62				
1452	New Waddell-Westwing 230 kV TL							402,866.70	115,898.01	818,875.76	2,022,579.38
1455	Liberty-Parker 230-kV TL	424.92	(486.40)	3,362.73	0.00	864.21	428.15				
1460	McCullough-Mead 230-kV TL										
1461	Mead-Davis 230 kV TL	64,739.58	9,013,542.16	1,387,496.88	16,877.34	444.40					
1462	Harcuvar-Little Har Pmp Plnt 115 kV TL	2,043,434.04	22,076.53	3,541.59	353.68	362.71					
1463	Harcuvar-Bouse Hills Pmp Plnt 115 kV TL	1,731,556.91	11,287.04	3,035.46	337.36	565.75	860.04		156.90		
1464	Hassayampa- Pmp Plnt 230 kV	15,545.97	1,781,290.15	10,596.04	3,558.55						
1465	Spook Hill-Salt Gila Pmp Plnt 69 kV TL	(270.73)	65,806.57	1,143,574.69	(581,686.33)	8,427.46	(52,593.40)				
1466	ED-2-Saguaro 115-kV TL	1,414.82	167,319.92	335,217.34	533,818.08	2,958,522.01	828,622.51	47,584.25	17,662.60	154.50	
1467	Blk Mtn-Del Bac 115 kV TL					3,555.53	26,364.76	108,365.36	307,359.01	156,374.28	312,162.95
1468	Rattlesnake Tap-Blk Mtn TL					79,296.22	16,032.75	266,229.78	3,452,689.83	12,793.75	
1650	Davis Switchyard 230-kV Additions	17,452.33	48,636.93	4,098.47	918.63						
1655	Parker Switchyard 230-kV Additions	46,653.07	41,850.78	50,998.55	26,219.68	(24,823.20)	397.60				
1660	Liberty Substation Additions	(765.93)	240.78	2,189.98		61.51					
1662	McCullough Switching Station Additions	3,311,386.05	1,164,403.62	196,045.56	9,309.92						
1663	Coolidge Substation Additions				39,719.79	16.73	20,551.70				
1670	Harcuvar Substation	4,069,345.00	662,260.71	199,015.57	15,666.08	1,396.20	5,431.46	2,963.57	1,072.80	2,871.94	362.44
1671	Hassayampa Substation	604,135.93	377,465.15	67,088.65	14,026.89	658.29	1,229.54	(23,933.00)			
1672	Spook Hill Substation	115,999.02	234,615.20	760,860.94	1,788,555.06	152,055.42	23,405.63				
1673	New Waddell Westwing Substation							926.83		46,228.18	589,362.40
1675	ED-2 Substation Additions	327.80	2,001.51	8,769.67	203,286.37	655,819.17	401,016.25	588,945.66	2,919.45	166.57	
1676	Saguaro Substation Additions		2,093.36		6,854.80	421,645.22	116,571.47	2,430.63	4,635.68		
1677	Rattlesnake Tap Substation			1,197.01	93,762.91	167,709.42	110,357.68	1,714,485.19	214,887.41	22,125.31	16,474.10
1678	Del Bac Substation					7,478.83	8,637.26	26,115.55	142,646.46	215,219.27	449,554.79
	Construction Costs	12,155,394.36	14,853,962.31	4,251,217.88	2,221,136.62	4,605,045.83	1,509,116.02	3,137,582.95	4,259,928.15	1,274,809.56	3,390,496.06
3.342%	Interest During Construction [1/]	1,272,589.15	1,723,915.50	2,043,163.06	2,151,316.10	2,265,381.61	2,367,549.25	2,445,195.59	2,568,808.00	2,661,293.47	2,739,250.73
TOTAL INVESTMENT COST		**13,427,983.51**	**16,577,877.81**	**6,294,380.94**	**4,372,452.72**	**6,870,427.44**	**3,876,665.27**	**5,582,778.54**	**6,828,736.15**	**3,936,103.03**	**6,129,746.79**

1/ IDC = (1/2 Current Year Construction Cost MULTIPLIED BY Pr
Project Declared Substantially Complete In FY 1993. Repayme

CENTRAL ARIZONA PROJECT
CONSTRUCTION COSTS OF TRANSMISSION LINES, SUBSTATIONS, AND SWITCHYARDS
FROM INCEPTION THROUGH SEPTEMBER 30, 2004

COST AUTHORITY	DESCRIPTION	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
1450	Davis-Parker No. 2 230-kV TL										
1451	Parker-Havasu 230 kV TL										
1452	New Waddell-Westwing 230 kV TL	1,203,389.37	20,501.97	11,729.59	27,802.49	199.00	308.50				
1455	Liberty-Parker 230-kV TL										
1460	McCullough-Mead 230-kV TL										
1461	Mead-Davis 230 kV TL										
1462	Harcuvar-Little Har Pmp Plnt 115 kV TL										
1463	Harcuvar-Bouse Hills Pmp Plnt 115 kV TL										
1464	Hassayampa- Pmp Plnt 230 kV										
1465	Spook Hill-Salt Gila Pmp Plnt 69 kV TL										
1466	ED-2-Saguaro 115-kV TL										
1467	Blk Mtn-Del Bac 115 kV TL	4,453,335.46	2,983,531.15	1,402,667.45	131,169.80	30,072.41	48,090.15	133,813.64	(1,057,698.40)	898.07	292.15
1468	Rattlesnake Tap-Blk Mtn TL										
1650	Davis Switchyard 230-kV Additions										
1655	Parker Switchyard 230-kV Additions										
1660	Liberty Substation Additions										
1662	McCullough Switching Station Additions										
1663	Coolidge Substation Additions										
1670	Harcuvar Substation										
1671	Hassayampa Substation										
1672	Spook Hill Substation										
1673	New Waddell Westwing Substation	167,476.79	32,826.52	29,677.36	7,476.17	528.09					
1675	ED-2 Substation Additions										
1676	Saguaro Substation Additions										
1677	Rattlesnake Tap Substation	8,434.36	(8,827.68)								
1678	Del Bac Substation	2,043,965.06	383,496.97	11,255.33	177.55	1,212.68	8,846.94	12,623.02			
	Construction Costs	7,876,601.04	3,411,528.93	1,455,329.73	166,626.01	32,012.18	57,245.59	146,436.66	(1,057,698.40)	898.07	292.15
3.342%	Interest During Construction 1/	2,927,523.92	3,116,148.57								
TOTAL INVESTMENT COST		**10,804,124.96**	**6,527,677.50**	**1,455,329.73**	**166,626.01**	**32,012.18**	**57,245.59**	**146,436.66**	**(1,057,698.40)**	**898.07**	**292.15**

1/ IDC = (1/2 Current Year Construction Cost MULTIPLIED BY Pr
Project Declared Substantially Complete in FY 1993. Repayme

CENTRAL ARIZONA PROJECT
CONSTRUCTION COSTS OF TRANSMISSION LINES, SUBSTATIONS, AND SWITCHYARDS
FROM INCEPTION THROUGH SEPTEMBER 30, 2004

COST AUTHORITY	DESCRIPTION	2002	2003	2004	TOTAL
1450	Davis-Parker No. 2 230-kV TL				8,948,407.75
1451	Parker-Havasu 230 kV TL				1,802,837.13
1452	New Waddell-Westwing 230 kV TL				4,624,150.77
1455	Liberty-Parker 230-kV TL				13,133,335.75
1460	McCullough-Mead 230-kV TL				0.00
1461	Mead-Davis 230 kV TL				11,209,395.18
1462	Harcuvar-Little Har Pmp Plnt 115 kV TL				2,268,094.67
1463	Harcuvar-Bouse Hills Pmp Plnt 115 kV TL				1,881,191.31
1464	Hassayampa- Pmp Plnt 230 kV				2,019,122.58
1465	Spook Hill-Salt Gila Pmp Plnt 69 kV TL				604,829.12
1466	ED-2-Saguaro 115-kV TL				4,890,316.03
1467	Blk Mtn-Del Bac 115 kV TL				9,040,353.77
1468	Rattlesnake Tap-Blk Mtn TL				3,827,042.33
1650	Davis Switchyard 230-kV Additions				3,994,821.70
1655	Parker Switchyard 230-kV Additions				3,114,460.94
1660	Liberty Substation Additions				632,729.77
1662	McCullough Switching Station Additions				4,957,229.04
1663	Coolidge Substation Additions				82,711.62
1670	Harcuvar Substation				5,519,551.51
1671	Hassayampa Substation				1,170,861.48
1672	Spook Hill Substation				3,083,670.53
1673	New Waddell Westwing Substation				874,502.34
					0.00
1675	ED-2 Substation Additions				1,863,252.45
1676	Saguaro Substation Additions				554,231.16
1677	Rattlesnake Tap Substation				2,340,605.71
1678	Del Bac Substation				3,311,229.71
	Construction Costs	0.00	0.00	0.00	95,748,934.35
3.342%	Interest During Construction [1/]				32,303,050.83
TOTAL INVESTMENT COST		**0.00**	**0.00**		**128,051,985.18**

1/ IDC = (1/2 Current Year Construction Cost <u>MULTIPLIED BY</u> Pr
Project Declared Substantially Complete in FY 1993. Repayme

APPENDIX F

DOE ORDER RA 6120.2

US. Department of Energy
Washington, D.C.

ORDER

RA 6120.2
9-20-79

SUBJECT: POWER MARKETING ADMINISTRATION FINANCIAL REPORTING

1. PURPOSE. To establish financial reporting policies, procedures, and methodology for all Department of Energy (DOE) power marketing administrations (PMA's) except, where deviations, therefrom are specifically approved by the Secretary, authorized by statute, or identified and explained in a transmittal memorandum or in the footnotes to the reports.

2. CANCELLATION. Paragraph IV. F of INTERIM MANAGEMENT DIRECTIVE 1701, PRICING OF DEPARTMENTAL SERVICES AND PRODUCTS, OF 9-28-77.

3. SCOPE. The provisions of this order apply to the PMA's reporting to the Assistant Secretary for Resource Applications.

4. REFERENCES. Proposed procedures for adjustments in power and transmission rates of the PMA's, 44 F.R. 39184 (July 5, 1979), or such finally adopted procedures.

5. AUTHORITY. This order is issued pursuant to the authority of the Secretary of Energy under the Department of Energy Organization Act, Public Law 95-91, 42 U.S.C. 7101; the Reclamation laws, particularly Section 9(c) of the Reclamation Project Act of 1939, 53 Stat. 1194, 43 U.S.C. 485h(c); Section 5 of the Flood Control Act of 1944, 58 Stat. 890, 16 U.S.C. 825s; the Bonneville Project Act, 50 Stat. 731, as amended, 16 U.S.C. 832 et seq.; the Federal Columbia River Transmission System Act, Public Law 93-454, 16 U.S.C. 838 et seq.; the Eklutna Project Act, 64 Stat. 382, as amended; Section 204 of the Flood Control Act of 1962, 76 Stat. 1193 (Snettisham Project); Reorganization Plan No. 3 of 1950, 64 Stat. 1262; Section 2 of the Act of June 14, 1966, Public Law 89-448, 80 Stat. 200, as amended; Section 303 of the Federal Power Act. 49 Stat. 855, 16 U.S.C. 825b; and related laws.

6. POLICY.

   a. It is DOE policy to encourage sound businesslike financial management and accounting practices in routine accounting and the preparation of power system financial statements.

DISTRIBUTION:
Power Marketing Administrations

INITIATED BY
Office of Power Marketing Coordination

Power system financial statements will be prepared in accordance with generally accepted accounting principles as prescribed by the American Institute of Certified Public Accountants, the Financial Accounting Standards Board, the General Accounting Office, and the Office of Management and Budget, as appropriate. To the extent practicable, the PMA's will maintain their accounts in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission for public utilities.

b. It is also DOE policy that power repayment studies will be prepared annually using sound and consistent financial forecasting techniques. These forecasts should be designed to approximate as closely as possible the results expected to be achieved in the historical power system financial statements.

7. DEFINITIONS.

a. Assisted Irrigation Investment. "Assisted irrigation investment" means the portion of construction costs of Federal Reclamation projects which are allocated to the irrigation purpose and are assigned pursuant to legal authorization for repayment from the revenues of the power system.

b. Cost Evaluation Period. "Cost evaluation period" means a period of time during which estimates of future costs and revenues may be modified to reflect changing conditions, normally 5 years.

c. Cost Recovery Criteria. "Cost recovery criteria" means the criteria set forth in paragraph 12, beginning on page 13.

d. Investment or Power Investment. "Investment" or 'power investment" means unless otherwise indicated in the context, investment allocated to be repaid from power revenues.

e. Power Marketing Administration. "Power marketing administration" means the Alaska Power Administration, the Bonneville Power Administration, the Southeastern Power Administration, the Southwestern Power Administration, or the Western Area Power Administration.

f. Power Repayment Study. "Power repayment study" means a study (previously referred to as an average rate and repayment study or repayment study) portraying the annual repayment of power production and transmission costs of a power system through the application of revenues over the repayment period of the power system. The study shows, among other items, estimated revenues and expenses, year by year, over the remainder of the power system's repayment period (based upon conditions prevailing over the cost evaluation period), the estimated amount of Federal investment amortized during each year, and the total estimated amount of Federal investment remaining to be amortized. The study does not deal with rate design. Power repayment studies may take two forms as described below:

(1) Current Power Repayment Study. A power repayment study that utilizes currently established rates for estimating future revenues. The study reflects the same basic power system included at the time rates were approved.

(2) Revised Power Repayment Study. A study that utilizes, in whole or in part, proposed or assumed rates for estimating future revenues. Typically, it is designed to demonstrate that potential revenue levels will satisfy the cost recovery criteria over the remainder of the power system's repayment period.

g. Power System. A system comprised of one project or more than one project hydraulically and/or electrically integrated and therefore treated as one unit for the purpose of establishing rates.

h. Power System's Repayment Period. A period extending to the final year allowed under the cost recovery criteria for amortization of the original investment in all projects included in the power repayment study.

i. Secretary. The Secretary of Energy.

8. THE ACCOUNTING SYSTEM.

a. The Books of Account. The books of account of all the PMA's will be kept in accordance with accounting systems that are approved by the General Accounting Office and any additional guidelines promulgated by the Secretary. The PMA's shall maintain their power systems accounts in accordance with the uniform system of accounts prescribed by the Federal Energy Regulatory Commission for public utilities and licensees to the extent practicable. Supporting detailed information shall be maintained in a manner that facilitates a ready retrieval, analysis, and verification of pertinent facts. Books of account shall be kept on a monthly basis and closed at the end of each fiscal year.

b. Accounting Concepts. Accounting concepts for PMA's shall be developed around, but not limited to, the following generally accepted principles:

(1) Period Cutoff Accounting. There must be proper cutoff accounting at the beginning and end of the period to ensure that revenues and expenses are not overstated or understated.

(2) Expenses Matched to Period Revenues. Expenses shall be appropriately matched against the periodic revenues.

(3) Current and Fixed Assets. Assets shall be accounted for in a meaningful manner to assure fair presentation of the financial position. Current assets are to be carried at cost or market value, whichever is less; fixed assets are to be carried at cost of acquisition or construction; appropriate charges shall be made for depreciation of fixed assets.

(4) Liabilities. All known liabilities shall be recorded.

c. Specific Power System Accounting Matters. Specific accounting matters which are pertinent to PMA practices include, but are not necessarily limited to, the following:

(1) Interest Rates. Interest expense on the power investment shall be a required portion of the costs to be recovered by power revenues. Rates to be used in computing interest shall be those rates officially established by law, or for all investment with no rate established by law made through 1-29-70, the rate established administratively for such investment, or for all investment made after 1-29-70, the rate established pursuant to paragraph 11, beginning at page 12, and related implementation guidelines.

(2) Unpaid or Deferred Annual Expense. Deficits (or unrecovered expenses) which occur in any year in which revenues fail

to recover operation and maintenance, purchased and exchanged power, transmission service and other expenses, and interest expense shall be accrued on the balance sheet as a liability with interest at the rate prescribed in paragraph 11, beginning at page 12, for investment made in the fiscal year in which the loss was incurred.

(3) Priority of Revenue Application. Annual revenues will be first applied to the following recovery of costs during the year in which they are incurred: operation and maintenance (O&M), purchased and exchange power, transmission service and other, and interest expense and any appropriation amortization of revenue bonds. Remaining revenues are available for amortization and shall be applied first to unpaid or deferred. annual expense, if any, and then to the Federal investment. To the extent possible, while still complying with the repayment periods established for each increment of investment and unless otherwise indicated by legislation, amortization of the investment will be accompanied by application to the highest interest-bearing investment first.

9. FINANCIAL STATEMENTS

a. Power System Financial Statements. Power system financial statements shall, to the extent practical, be prepared in accordance with generally accepted accounting principles and concepts. Power system financial results shall be disclosed in a clear, concise, and complete manner. Annual financial statements, accompanied by explanatory footnotes and supporting schedules, shall fairly present the financial position for each PHA power system. Power system reporting requirements shall generally conform to any appropriate standards promulgated by the American Institute of Certified Public Accountants, the Financial Accounting Standards Board, the Federal Energy Regulatory Commission, and the General Accounting Office and shall include, but not necessarily be limited to (1) Statement of Revenues and Expenses or Income Statement; (2) Statement of Assets and Liabilities or Balance Sheet; (3) Statement of Source and Application of Funds or Statement of Changes in Financial Position; (4) Statement of Changes in Proprietary Capital (this statement may be incorporated in either the Statement of Revenues and Expenses or the Statement of Assets and Liabilities); and (5) the appropriate notes to financial statements.

b. <u>Statement of Revenues and Expenses (Income Statement)</u>. The results of operations shall be clearly and fairly reported on a comparative basis for the current and preceding fiscal periods. Net Revenues (or Deficit) presents the results of power system operations on a normal accrual accounting basis for the reporting period, after depreciation expense and interest on the unpaid Federal investment.

c. <u>Statement of Assets and Liabilities (Balance Sheet)</u>. The financial position of the power system for the current and preceding periods shall present the Federal investment in the power system on a cumulative basis and include a schedule of accumulated net revenues.

d. <u>Statement of Changes in Financial Position (Statement of Source and Application of Funds)</u>. A statement of changes in financial position shall be prepared on a comparative basis for the current and preceding fiscal periods to clearly describe the flow of funds of the power system for the reporting period. All power system funds shall be reported according to major source and disposition in a format which is appropriate to conventional regulated-company financial reporting.

e. <u>Notes to the Financial Statements and Supporting Tables</u>. Power system financial statements shall satisfy professional requirements for adequate, informative disclosure. Notes to the financial statements for each power system shall address, as a minimum, the following reporting matters (unless this information is provided elsewhere):

(1) <u>Summary of Significant Accounting Policies</u>. A description of all significant accounting policies of the power system. Policy disclosures shall include, at a minimum: (a) the basis of consolidation. (b) depreciation methods employed, (c) status of allocation of cost varying purposes on multi-purpose projects, and (d) amortization and repayment requirements related to the Federal power investment.

(2) <u>Subsequent Events</u>. Disclosure of material events and transactions occurring subsequent to the financial reporting period shall be included if necessary for proper interpretation of the financial statements.

(3) interest Rates. Current policy regarding interest rates applicable to the reporting power system.

(4) Non-depreciable Assets. The amortization and reporting treatment of the Federal investment in land and other non-depreciable assets.

(5) Contingent Liabilities. A discussion of known major contingent liabilities.

f. Auditor's Opinion. The financial statements and accompanying notes to the financial statements of each power system shall be examined periodically, with the period not to exceed 2 years, by independent auditors, the General Accounting Office, Inspector General, or other acceptable audit organization. The results of this examination shall be reported in a letter which describes the scope of the examination and expresses an opinion on the financial statements.

10. POWER REPAYMENT STUDIES.

a. General Requirements. Each PMA will prepare and publish annually a power repayment study for each power system. Each power repayment study consists of two parts, historical data and future data (forecasts). The development of future data requires the forecast of revenues, expenses and investment. The annual power repayment study will use sound and consistent forecasting techniques. Those forecasting techniques will be explained in a memorandum included with each forecast. The forecasts will utilize, to the extent possible, the accounting concepts set forth on page 4, paragraph 8. The power repayment study is updated annually to test the continuing adequacy of the existing rates. The annual study is called a Current Power Repayment Study. It reflects the same basic power system included at the time rates were approved, but forecasts Current operating results and updated estimates of revenues and costs for the remaining years of the repayment study.

b. Rate Adjustment Plan. Whenever the current power repayment study shows that repayment requirements are not being met, action will be taken by the PMA to prepare and recommend a plan to be implemented at the next practicable time to satisfy the repayment requirements (or to explain why such requirements cannot be met).

Such plan may include increasing rates, decreasing costs, changing contracts, or any other viable means for meeting cost recovery criteria. This plan will be supported by a Revised Power Repayment Study which will meet the cost recovery criteria. The plan will be submitted to the Assistant Secretary for Resource Applications through the Office of Power Marketing Coordination for review and further action. In certain situations the plan could recommend that no action be taken to meet repayment requirements. While a revised power repayment study must be prepared at a minimum when a current power repayment study shows that repayment requirements are not being met, preparation is not limited to that situation.

c. Cost Evaluation Period. A period of time during which future estimates of costs and revenues may be modified to reflect changing conditions, such as additions to the power systems or inflation. This period of time is normally 5 years. Revenue and cost estimates for the remaining years of the power system's repayment period should reflect price levels, rate levels, and contractual commitments consistent with conditions anticipated during the cost evaluation period.

d. Allowable Unamortized Investment. Each increment of investment shall be carried as allowable unamortized investment for its repayment period in accordance with the following principles:

(1) Duration of Repayment Period. Unless otherwise prescribed by law, each dollar of investment is to be repaid with interest within a period not-to-exceed 50 years. Repayment periods of less than 50 years may be established when the facilities involved have useful life expectancies of less than 50 years. Such shorter repayment periods are appropriate for (a) replacement of power facilities and (b) transmission facilities which are developed and managed as transmission systems rather than as adjuncts to generating projects. In such cases, the expected useful life of the facility involved generally will be used as the repayment period. Such repayment periods may be adjusted from time to time, within the 50-year maximum, if changed conditions indicate a different estimated useful life expectancy.

(2) Start of the Repayment Period. The first year of the repayment period for both specific and joint investment cost shall be the fiscal year following the fiscal year in which the investment goes into commercial service. After each portion of allocated repayable power investment goes into commercial service, the total joint investment costs for a power generating facility shall, on a pro rata basis, be associated with the specific investment costs incurred in the initial stage of project development (the initial stage of development includes all power units which are initially constructed in a continuous sequence without a time lag or more than 5 years between generating units).

e. Revenues.

(1) Power revenues shall be those expected through the power system's repayment period, based on contractual commitments for sales of power and energy that are expected to exist during the cost evaluation period.

(2) In the absence of specific contractual provisions for increased power sales, the revenue forecast will rely heavily on the past trends of actual customer load growth rates. Where contractual payments for power and/or quantities of such power and energy sales are defined. these shall form the basis for revenue determination.

(3) Power quantities for forecasting future revenues shall also include purchased and exchange power quantities which are consistent with contractual commitments that are estimated to exist during the cost evaluation period, and only to the extent that related costs are also projected. The revenue forecast shall also consider capacity increases resulting from facility additions which are projected to be commercially operational within the cost evaluation period. A schedule comparing revenue estimates for the previous period with actual revenue realized should be included with the annual submission. Miscellaneous revenues shall be included where appropriate, as well as headwater benefit payments to be made to the Treasury for power benefits to non-Federally owned utility hydro plants.

(4) Power quantities used for estimating revenues, unless defined by contract, are determined by theoretical reservoir operation studies based on historical stream flows. In preparing these operational studies, hydrological data, current to within 5 years if possible, and available engineering data will be used, recognizing restrictions imposed by other project functions. Input data will be revised and updated whenever new information indicates that a significant change in the forecast can be expected in the future where there is a significant variance between the forecasted and actual results, but in any event not less frequently than once every 5 years unless an accepted explanation is provided concerning why this is not necessary.

f. Operation and Maintenance Costs. Estimates of O&M costs shall be developed with heavy reliance placed on historical cost trends and actual project costs in the past. The use of various cost indices, developed from and supported by project history, is recommended in developing the forecastand testing its reliability. In preparing the estimate, actual costs will be compared to past forecasts to identify sources of variance and previous projection errors. A schedule showing these comparisons will be included with the annual power repayment update. The forecast shall take into account known factors which are expected to affect the future level of such costs during the cost evaluation period.

g. Purchased and Exchange Power Costs. All costs of planned purchased power during the cost evaluation period shall be included in the power repayment study.

h. Transmission Service and Other Costs. These costs, to be estimated for the cost evaluation period, include payments to others required by legislation, 'wheeling' payments for use of transmission capacity, rental payments for the use of electrical facilities, payments for detriment caused by project facilities or operation, payments for increased benefits furnished by others, credit payments under certain contracts, and interconnection costs for which a payment is made based on contractual commitments.

i. interest Rates. Interest rates shall be established as set forth on page 4, paragraph Bc(1) for historical and current rates. Forecasts will utilize the rate established in paragraph 11, beginning on page 12, and related implementation guidelines for the latest available year for all future years.

j. Interest Expense. Interest expense for each of the years of the study will be the sum of the amounts determined by: (1) applying the applicable interest rate to each estimated unamortized power investment at the beginning of the year; plus (2) applying one-half the applicable interest rate to power investments (i.e., additions and replacements) expected to be added and in service during the year; plus (3) applying the applicable interest rate to capitalized unpaid or deferred annual expense, if any. If the interest credit concept is utilized by the PMA, the interest credit should be offset against interest expense.

k. Investment Costs. The power repayment studies will include all investment cost allocated to power for the existing systems. Additionally, the allocated power investment costs of all authorized power system facilities for which Congress has appropriated funds for construction and which will be in service within the cost evaluation period will be included. The investment cost will include construction cost of the project as well as interest during construction, computed using the same rate as determined in paragraph 10i.

l. Replacements. Future replacement costs will be included in repayment studies by adding the estimated capital cost of replacement to the unpaid Federal investment in the year each replacement is estimated to go into service, and adding it to the allowable unamortized investment. The capital costs of each replacement is determined by estimating the cost at current price levels of the new unit of property, less salvage, if any, at the end of the service life of the unit replaced. The allowable unamortized investment is developed by adding each years investment as it goes into service and then deducting each increment of investment at the end of its allowable repayment period. Replacements should be accounted for separately from the original investment.

p. Status of Repayment. For any year of a power system study, the status of repayment can be determined by comparing the allowable unamortized investment with the unamortized investment. For every year that the unamortized investment is equal to or less than the allowable unamortized investment, repayment is on or ahead of schedule. If for any year the unamortized investment exceeds the allowable, the cost recovery criteria are not being met.

n. Content and Format of Power Repayment Study. Power repayment studies for all power systems shall be accompanied by a statement of pertinent assumptions used in preparing the studies. Further, there should be submitted a schedule which will show significant changes as compared with the previous study and a comparison of the previous forecast to actual performance for the same period. The format of the power repayment studies prepared by the PMAs will be expected to vary to some extent due to differences in conditions among PMAs, e.g., some have transmission systems, while others do not.

11. INTEREST RATE FORMULA.

a. Except as otherwise provided by law, the interest rate to be used for computing interest during construction and interest on the unpaid balance of the costs of Federal power facilities, the construction of which is initiated after September 30, 1983, which are financed with appropriations and the cost of which is properly allocated to commercial power development, shall be the yield rate, as hereinafter provided in subparagraph 'b" of this paragraph, during the fiscal year in which construction Is initiated. For purposes of this paragraph, the facilities for which a separate interest rate is established may be any of the following as long as repayment periods are established for them:

(1) A Federal reservoir or canal project which includes the generation of electric power that is marketed by a PMA and which may also include transmission facilities constructed during the same stage of construction;

(2) Any unit or separable power feature or groups of such units of features of such Federal reservoir or canal project;

(3) Any separable features or groups of features of a Federal transmission system, including transmission lines, substations, and appurtenant facilities, which are under the administration of a PMA that are not considered a part of a Federal reservoir or canal project;

(4) Annual increments of investment in separable features or groups of features of a Federal transmission system that are placed in service during the same year; or

(5) Replacements of or additions or betterments to power facilities.

b. Each fiscal year the Assistant Secretary for Conservation and Renewable Energy will request the Secretary of the Treasury to provide the computations made as of October 1 of the yield rate for the preceding fiscal year. For purposes of this paragraph, the yield rate is the average yield during the preceding fiscal year on interest-bearing marketable securities of the United States which, at the time the computation is made, have terms of 15 years or more remaining to maturity. The average yield shall be computed as the average during the fiscal year of the Gaily bid prices. Where the average yield so computed is not a multiple of one—eighth of one percent, the yield rate shall be the multiple of one-eighth of one percent nearest to such average yield.

c. The Assistant Secretary shall annually notify the PMAs of the yield rate for the current fiscal year.

12. COST RECOVERY CRITERIA. The current rates for a power system will be adequate if. and only if, a power repayment study indicates that:

a. The expected revenues are at least sufficient to recover annually, except for a possible initial short transition period:

(1) All costs of operating and maintaining the power system during the year in which such costs are incurred; plus,

(2) The cost of acquiring power through purchase and/or exchange agreements, the costs for transmission services, and other costs during the year in which such costs are incurred; plus,

(3) Expensed interest on the unamortized investment in Federal power facilities in the year for which the interest charges are assessed, except that recovery of the annual interest expense may be deferred in unusual circumstances for short periods of time; plus,

(4) Interest and amortization of revenue bonds where PMAs are authorized to issue such bonds.

b. In addition to the recovery of the above costs on a year-by-year basis, the expected revenues are at least sufficient to recover:

(1) Each dollar of power investment at Federal hydroelectric generating plants within 50 years after they become revenue producing, except as otherwise provided by law: plus,

(2) Each annual increment of Federal transmission investment within the average service life of such transmission facilities or within a maximum of 50 years, whichever is less; plus,

(3) The cost of each replacement of a unit of property of a Federal power system within its expected service life up to a maximum of 50 years; plus,

(4) Each dollar of assisted irrigation investment within the period established for the irrigation water users to repay their share of construction costs; plus,

(5) Other costs such as payments to basin funds, participating projects or States.

23. SUBMISSION. Power system financial statements and power repayment studies will be forwarded to the Assistant Secretary for Resource Applications and shall be accompanied by a statement from the PI4A Administrator that the financial statements and power repayment studies are in compliance with this order. Any deviation therefrom shall be disclosed and justified. Copies of power system financial statements and power repayment studies will be provided for policy guidance, evaluation of methodology, and compliance review, and shall be delivered within 180 days of the close of the applicable fiscal year.

FOR THE SECRETARY OF ENERGY:

George S. McIsaac
Secretary for
Resource Applications

APPENDIX G

COURT REPORTER

To obtain a verbatim transcript of today's Public Information Forum, please contact the following:

Brush & Terrell
Court Reporters
23331 N. 90th Drive
Peoria, AZ 85323
(623)-506-8046

Copies will be made available to anyone desiring a copy, upon payment of the required fee to the court reporting firm.